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Simulation of the Impact of Fracturing Fluid Induced Formation Damage in Shale Gas Reservoirs

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Abstract

Unconventional gas resources from tight and shale gas reservoirs have received great attention in the past decade and become the focus of petroleum industry. Shale gas reservoirs have specific characteristics, such as tight reservoir rock with nano-Darcy permeability. Multi-stage hydraulic fracturing is required in such reservoirs to create very complex fracture networks to connect a huge reservoir area to the wellbore effectively. During hydraulic fracturing, an enormous amount of water is injected into the formation, and only a part of the injected water (25-60%) can be reproduced during a flowback and long production period. A major concern with hydraulic fracturing is water blocking effect in tight formation due to high capillary pressure and the presence of water sensitive clays. High water saturation in the invaded zone near the fracture face may reduce greatly gas relative permeability and impedes gas production.

In this paper, we will consider numerical techniques to simulate water invasion or formation damage during hydraulic fracturing and its impact on the gas production in shale-gas reservoirs. Two-phase flow simulations are considered in a large stimulated reservoir volume (SRV) containing extremely-low permeability tight matrix and multi-scale fracture networks including primary hydraulic fractures, induced secondary fractures and natural fractures.

To simulate water blocking phenomena, it is usually required to explicitly discretize the fracture network and use very fine meshes around the fractures. On one hand, the commonly used single-porosity model is not suitable for this kind of problem, because a large number of gridblocks is required to simulate the fracture network and fracture-matrix interaction. On the other hand, a dual-porosity model is not suitable either, because of large block sizes and long transient duration with ultra-low permeability matrix. In this paper, we study the MINC (Multiple INteracting Continuum) type method and use a hybrid approach between matrix and fractures to simulate correctly fracturing fluid invasion and its backflow under hydraulic fracturing. This approach allows us to quantifying with satisfactory the fracturing water invasion and its formation damage effect in the whole SRV.

Introduction

Most shale gas reservoirs are fractured and have low matrix permeability. Additionally, matrix contains the most gas volume, where global flow in the reservoir is assumed to occur through the network of primary hydraulic fractures, induced and stimulated natural fractures. Note that fractures play an

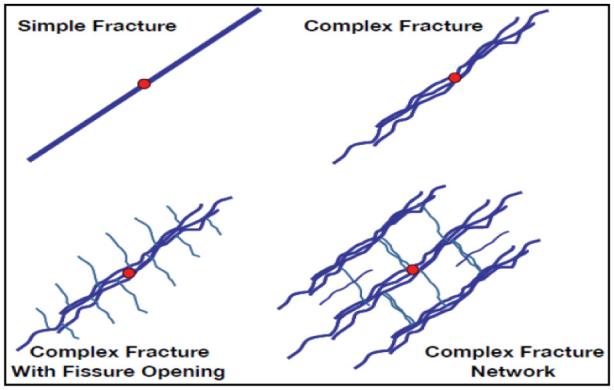


Figure 1—Schematic of the level of hydraulic fracture complexities (after; Warpinski et al., 2008).

important role in gas production from shale formations. Horizontal drilling and multi-stage hydraulic fractures are required and widely used to create complex fracture network in a shale gas reservoir. An enormous amount of water is injected into the formation during the fracking operation to create a large stimulated reservoir volume (SRV), where only a part of pumped water (25-60%) can be reproduced during flowback for a long production period and large quantities of fracturing fluid are still blocked in the formation. A major concern with hydraulic fracturing is water blocking effect in tight formation due to high capillary pressure and the presence of water sensitive clays. Additionally, several mechanisms such as imbibition, relative permeability, gravity segregation and stress-sensitive fracture conductivities will control the behavior of blocked water. High water saturation in the invaded zone near the fracture face will reduce greatly gas relative permeability and impede gas production.

Fracturing fluid induced formation damage has been studied in the literature since a long time (see, for example, Holditch, 1979; Friedel, 2004; Gdanski et al. 2006; Wang et al. 2009; Ding et al., 2013). Recently, the fracturing fluid induced formation damage is particularly discussed in extremely low-permeability shale gas reservoirs. Li et al. (2012) used an analytical model to study fracture-face matrix damage in shale gas reservoirs. Cheng (2012) investigated formation damage effect with a numerical model. Agrawal and Sharma (2013) used a 3D numerical simulator to study gravity effect. Bertoncello et al. (2014) compared with experimental data and studied fracturing fluid induced formation damage by modeling the flow into a single hydraulic fracture in a shale-gas reservoir. However, few work discuss the efficient simulation methods and the impact of formation damage in a large SRV. In fact, the simulation of fracturing induced formation damage in a scale of SRV requires generally a great number of gridblocks and consequently a very large CPU time, which makes the simulation prohibitive. In this paper, we focus our study on the hydraulic damage by simulating the full process of fracturing fluid invasion followed by a cleanup of loaded fluid in a complex fracture network in the whole stimulated reservoir volume.

The necessary of full-field information for the hydraulically fractured well simulation has been discussed in the literature (see, for example, Ehrl and Schueler 2000; Sadrpanah et al. 2006; Lolon et al. 2007; Fazelipour, 2011; Delorme et al. 2013). In shale-gas formations, it is particularly needed to take into account the presence of complex fracture network, including stimulated and non-stimulated natural fractures, and its contribution to the gas production.

One of the critical issues in numerical modeling for shale gas reservoirs is how to handle fluid flows in the presence of a complex fracture network and the interaction between tight matrix formation and fractures (see Fig. 1). Using a single-porosity model by discretizing explicitly fractures is a solution, but this approach needs a great number of cells and hence a large CPU time. Cipolla et al. (2009b) and Rubin (2010) propose to use LS-LR-DK (Logarithmically Spaced, Locally Refined, and Dual Permeability) grid to reduce the number of cells with a single-porosity model. That technique uses large fracture cells (for example, 2 ft in width) to mimic low-aperture fractures (for example, 0.001 ft in aperture). Although

equivalent large gridblocks can approximate gas production for single-phase flow, it is not adapted to simulate fracturing fluid invasion with a two-phase flow model, where water invades into the matrix formation only several centimeters from the fracture face.

The dual-porosity model, where a shape factor is required to simulate the matrix-fracture interaction, is not suitable for shale-gas simulations, because of large gridblock size and long transient period due to extremely low matrix permeability. To improve the simulation for matrix-fracture interaction, especially for multi-phase flow problems, the multiple interacting continua (MINC) approach (Pruess and Narasimhan, 1983) seems to be a good alternative solution. The MINC method was used in many applications, for example in the chemical EOR processes (Farhadinia and Delshad, 2010), with satisfaction. Here, we present a hybrid approach, based on the MINC method to simulate fracturing fluid invasion and its backflow in shale-gas reservoirs.

In this work, we consider only the hydraulic modeling of fracturing fluid invasion without considering the geomechanical aspects of fracture generation. We assume that the fractures were already created, and the width and the fracture permeability (or conductivity) are known. The fracture propagation is not explicitly considered. The leakoff during the fracturing is represented by injecting an appropriate volume of fluid into the formations. The hydraulic fractures and stimulated natural fractures are considered as fracture media for fluid transports, while un-stimulated natural fractures are homogeneized in the matrix media. Interaction between matrix and fractures is modeled using very fine nested sub-matrix blocks to insure a good calculation of water invasion and water blocking effect due to high capillary forces. This approach allows us to obtain almost the same results as an explicit discretized fracture model with a gain of an order of magnitude of 2 - 4 in CPU time. Therefore, the study of fracturing induced formation damage and its impact on gas production can be achieved in the complex fracture network in a SRV in shale gas reservoirs with a reasonable CPU time.

Mathematical Model

Studying fracturing fluid induced formation damage needs the simulation of a multiphase flow system. Here, we consider a two-phase flow in a porous and fractured media, composed of gas and water. For simplicity, the gas and water components are assumed to be present only in their associated phases and adsorbed gas is within the solid phase of rock. Each fluid phase flows in response to pressure, gravitational, and capillary forces. Two mass-balance equations are needed to fully describe the system.

For a single-porosity two-phase flow model, Eq. (1) alone is used for flow simulation in the whole reservoir, with different petro-physical properties for matrix and fractures medias.

$$\frac{\partial}{\partial t}(\phi\, S_\beta \rho_\beta + m_g) + \nabla \bullet (\rho_\beta v_\beta) - q_\beta = 0\,, \tag{1}$$

where the subscript β representing phase with $\beta = g$ for gas and $\beta = w$ for water; ϕ is the porosity; S_β is the saturation of fluid β; ρ_β is the density of fluid β; v_β is the volumetric velocity vector of fluid β, determined by Darcy's law or non-Darcy's flow models, t is time; m_g is the adsorption or desorption mass term for gas component per unit volume of formation; and q_β is the sink/source term of phase (component) β.

Furthermore, in a dual porosity model, the mole conservation is applied to each component β in both matrix and fracture media by the following equations:

$$\frac{\partial}{\partial t}(\phi^m S_\beta^m \rho_\beta^m + m_g) + \nabla \bullet (\rho_\beta^m v_\beta^m) + Q_\beta^{mf} - q_\beta^m = 0\,, \tag{2}$$

$$\frac{\partial}{\partial t}(\phi^f S_\beta^f \rho_\beta^f) + \nabla \bullet (\rho_\beta^f v_\beta^f) - Q_\beta^{mf} - q_\beta^f = 0\,, \tag{3}$$

where the superscript m represents matrix media and f represents fractured media, Q_β^{mf} is the exchange term between the matrix and the fracture.

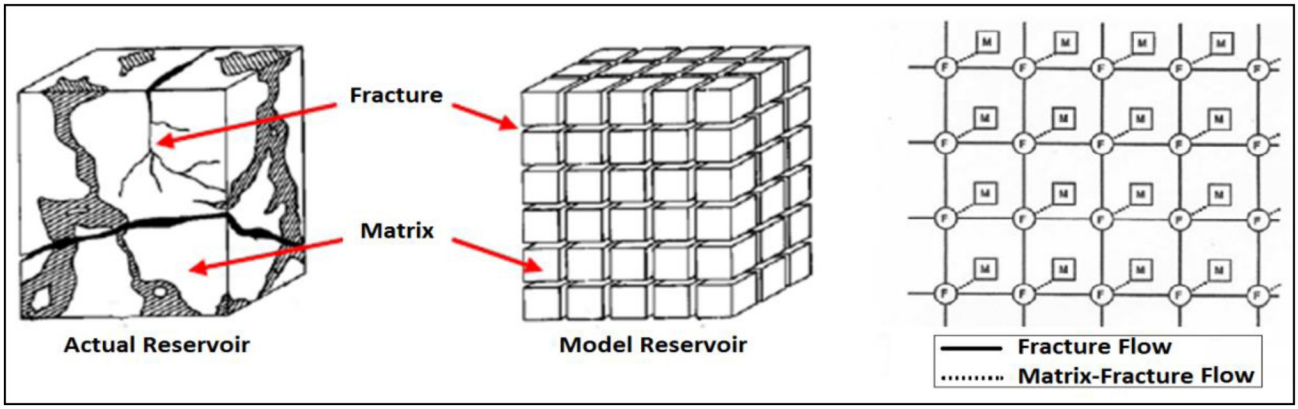


Figure 2—Flow connections in the dual porosity method (after; Karsten Pruess, 1992).

For a dual porosity model, flow exchange term between the matrix and the fracture is calculated by:

$$Q_{\beta}^{mf} = \lambda_{\beta}^{mf} \sigma \ (\Phi_{\beta}^{m} - \Phi_{\beta}^{f}) \ , \tag{4}$$

where λ_{β}^{mf} is the mobility term to phase β; Φ_{β}^{m} and Φ_{β}^{f} are the potentials in the matrix and fracture media respectively; σ is the shape factor, characterized by the matrix block geometry and matrix permeability under pseudo-steady-state flow.

In addition, the term m_g in Eqs. (1) and (2) is given by:

$$m_g = \rho_r \rho_g \ V_E \ , \tag{5}$$

where m_g is the absorbed gas mass per unit formation volume; ρ_r is rock bulk density; ρ_g is the gas density at standard condition; V_E is the adsorption isotherm function or gas content in scf/ton (or standard gas volume adsorbed per unit rock mass). The system of equations (Eqs. (2) and (3)) are discretized in space using a control-volume method, where time discretization is carried out using a backward, first order, fully implicit, finite-difference scheme.

MINC Method Concept

MINC stands for "Multiple INteracting Continua", developed by Pruess et al. (1982) and Pruess and Narasimhan (1983). Also, MINC is applicable to media where the fractures are well connected (fracture network) so that a continuum treatment of flow in the fracture can be made. MINC method is a generalization of the dual porosity (DP) concept, originally developed by Barenblatt et al. (1960) and Warren and Root (1963), a schematic diagram and fluid flow method in the dual porosity model is given in Fig. 2.

Fluids in a fractured-porous media will flow through the fractures to the well while matrix blocks can exchange fluid with the fractures. The main difference between MINC method and a DP model is in the matrix-fracture exchange known also by "inter-porosity flow". The DP method simulates matrix-fracture exchange on the basis of a pseudo-steady-state flow, while MINC method treats the problem entirely by numerical methods in a fully transient way. In other word, MINC method consists in a fully transient representation of the interporosity flow.

The concept of MINC method consists in partitioning of the matrix blocks into a sequence of nested volume elements as schematically shown in Fig. 3, where continuum #1 represents the fracture, continuum #2, 3, 4, 5 and 6 represents the matrix media. Note that Fig. 3 is a representation of MINC5, where 5 refers to the number of subdivisions in matrix media.

MINC method presents a solution concerning the matrix-fracture flow exchange, which seems suitable and more efficient than a standard dual porosity model. Additionally, in case of multi-phase (gas and

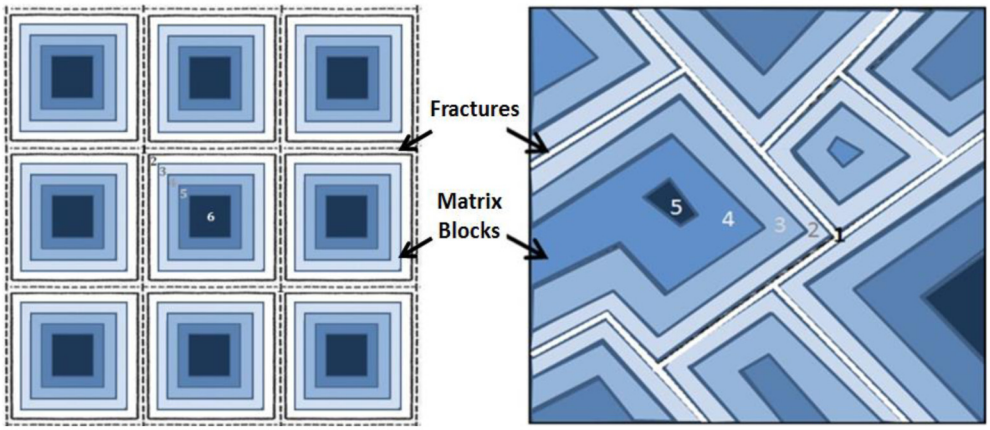


Figure 3—Schematic of MINC concept, (*left*) for a regular fractures network (after; Pruess and Narasimham, 1983), (*right*) for an arbitrary fractures distribution (after; Pruess, 1982, 1992).

water) flow simulations, very fine subdivisions near fracture are required to a better simulation of fluid invasion and its backflow after a hydraulic operation, which can be modeled and accurately simulated using MINC method.

Furthermore, the application of MINC method in partitioning the matrix media into nested volumes based on the distance from the fracture is not limited to a regular fractured network, but can also be applied to an irregular network.

Hybrid Approach based on the concept of MINC method

In general, unconventional gas reservoirs are naturally fractured, which increases the heterogeneity and complexity of reservoir simulations. The most commonly used numerical methods for flow simulations in these kinds of reservoirs are based on single porosity or dual porosity models. Un-stimulated natural fractures are homogeneized and considered as a part of matrix media. Simulations with explicitly discretized fractures using very fine gridblocks as fracture width with a single-porosity approach can give us a very accurate flow modeling into and from fractures, especially for two-phase flow problems. However, it involves a large number of cells which are not suitable for these reservoirs simulations due to the high CPU time. Moreover, the commonly used dual-porosity approaches based on pseudo-steady-state flow regime are inadequate for solving fluid flow from such reservoirs where the main problem is that we are dealing with tight reservoir rock with nano-Darcy permeability.

In this paper, we will present a hybrid approach based on the concept of MINC (Multiple Interacting Continua) method. The MINC approach was investigated by Ding et al. (2014) for the single-phase flow simulation in shale-gas reservoirs. The purpose of paper is to improve the two-phase flow simulation model via the matrix-fracture interaction in extremely low-permeability fractured reservoirs using MINC method. This approach consists in a hybrid discretization logarithmically spaced near fractures. Furthermore, study will focus on the impact of hydraulic damage due to fracturing fluid invasion into the tight formation by simulating the full process of fracturing operation in a complex fracture network from shale gas reservoirs.

We will also present the benefits of using a hybrid approach based on the concept of the MINC method. Firstly, this approach reduces the number of grid cells, which obviously could result in decreasing computational time. In fact, a flow simulation using this approach takes seconds or minutes rather than hours or days comparing to an explicit discretized model on the same hardware. Secondly, this approach is is accurate. We will show some comparisons with the reference solution (extremely refined grid with explicit fracture discretizations) for different fracture spacing. Additionally, various physical processes

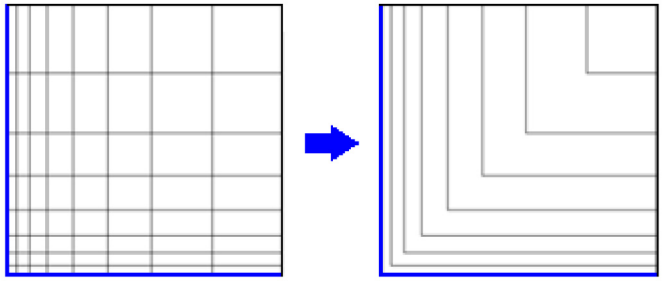


Figure 4—Two-dimensional fracture model, discretized model (left) and its MINC optimization using nested sub-grids (right).

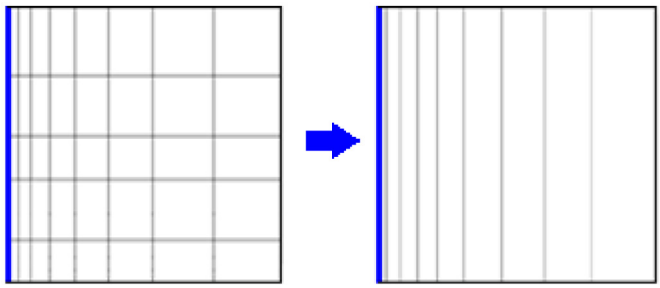


Figure 5—One-dimensional fracture model in y-direction and its optimization using the MINC method.

could be tested with this hybrid model, for example, adsorption/desorption, geomechanics, Klinkenberg aspect, etc.

As said before, the purpose of this method is to improve matrix-fracture flow exchange. Based on the MINC approach, matrix media are subdivided into several nested volumes, which look more suitable than a dual porosity/permeability model and can handle the physics of such flow. Note that, the MINC concept could be a solution of the interpososity flow, where this approach can treat this problem entirely by a fully transient representation of matrix-fracture flow exchange. We assume that the stimulated fracture network can be represented by regular fracture geometry with an uniform spacing in the SRV. So, we use standard MINC method inside SRV, and single-porosity approach in the non-stimulated zone. In the transient zone between SRV and non-stimulated volume, we use a generalized MINC approach by using nested fine cells around the fracture as shown in Fig. 4 and Fig. 5.

Moreover, to simulate correctly fracturing fluid invasion and its backflow, very fine cells should be used near the fractures for fracture-matrix interaction simulations as fluid invasion is generally not deep in the tight formation. Fluid transport should be considered in the multi-scale fracture network. This hybrid approach based on the concept of MINC method for a multiphase flow will be tested on a synthetic reservoir example, in order to show if it is able to handle physics of such flow by comparing it to an explicit discretized and a standard dual porosity model.

Numerical Example

In order to study the impact of fracturing fluid induced formation damage in shale gas reservoirs, simulations for a single-phase (gas only) flow were first performed to test the effectiveness of our approach based on the concept of MINC method. Once this approach is tested, a two-phase (gas and water) flow simulation will be performed to quantify the impact of formation damage on gas production from shale gas reservoirs.

Table 1 summarizes the reservoir properties. A horizontal well (red line in Fig. 6) in the x-direction is placed in the middle of the reservoir, where hydraulic fractures are perpendicular to the well along the y-direction. Note that, two areas exist in the reservoir model, the first one known as SRV and the other

Table 1—Reservoir properties.

Property / Parameter	Value
Matrix Permeability	0.0001 mD
Hydraulic Fracture Permeability (during hydraulic fracturing)	200 D
Hydraulic Fracture Permeability (during production)	2 D
Induced-fracture Permeability (during hydraulic fracturing)	40 D
Induced-fracture Permeability (during production)	0.5 D
Matrix Porosity	5 %
Fracture Porosity	50 %
Fracture Thickness	0.01 ft
Induced-fracture Thickness	0.001ft
Reservoir Net Thickness	300 ft
Top of the Reservoir	5800 ft
Initial Reservoir Pressure	3800 psi
Bottom Hole Well Pressure	1000 psi

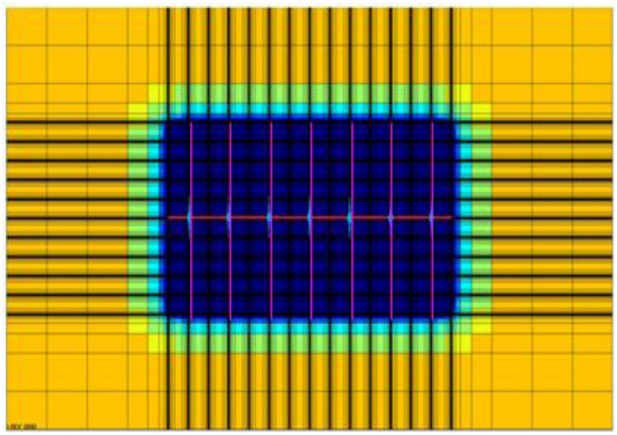


Figure 6—Explicit discretized fracture model with an horizontal well for Case1.

as non-SRV (Stimulated and non-Stimulated Reservoir Volume). The SRV has a volume of 1,400*1,000*300 ft^3 and centred in the model.

On one hand, a base model named "Explicit discretized model" (or Single Porosity model), meshed with a local grid refinement around the stimulated fractures, logarithmically spaced, is considered as a reference solution. Our reservoir model presents different scale of fractures in x and y-directions dedicated to hydraulic and induced fractures, where grids which are donated to the hydraulic fractures presented in y-direction have a width of 0.01 ft, a permeability of 2000 md (during production), while the stimulated natural fractures are presented in x and y-directions with a thickness of 0.001 ft and a permeability of 500 md (during production). On the other hand, the dual porosity model (DP) consists in two interconnected systems, named matrix and fracture. For the dual porosity model, the grid block size is 200ft in x and y directions. Comparisons are made between the reference solution and DP/Hybrid approach. Care was taken to be consistent in the calculation of the effective fracture permeability and porosity for the DP model, where the shape factor σ for calculating matrix-fracture exchange is given by:

$$\sigma = \frac{10}{a^2} + \frac{10}{b^2} \quad , \tag{6}$$

where a and b are the matrix block dimensions (in x and y directions).

Firstly, single-phase flow is treated. Later on, the two-phase (gas and water) flow problem is considered to simulate fracturing induced formation damage. We assume that the hydraulic fractures are already

Table 2—Representation of HF (Hydraulic Fractures), NFx and NFy (stimulated Fractures in x and y directions) for the three considered cases.

Case	Fracture Spacing	Number of HF	Number of NFx (stimulated fractures parallel to the well direction)	Number of NFy (stimulated fractures perpendicular to the well direction)
Case1	100 ft	7	11	8
Case2	50 ft	7	21	22
Case3	25 ft	7	41	50

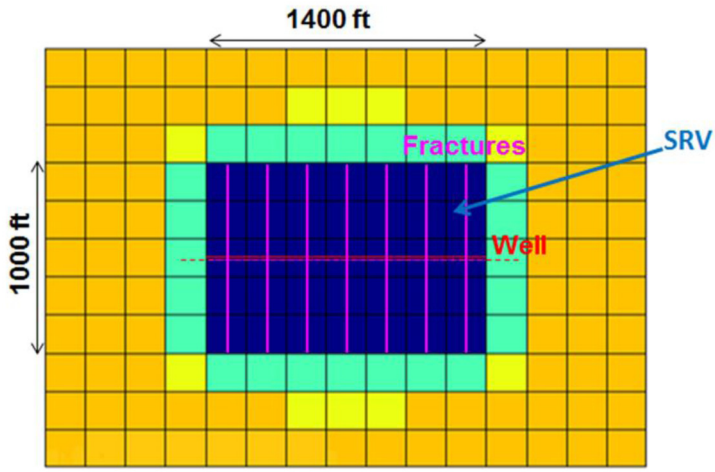


Figure 7—Dual porosity model for Case1 (Fracture spacing of 100ft).

created, and we do not consider the geomechanics effects in our simulations. Three cases are considered for different fracture spacing. Table 2 summarizes these three cases.

In all cases, 7 hydraulic fractures perpendicular to the well direction are created. Inside the SRV zone, for Case1, the induced/stimulated fractures can be approximated by a fracture network with a spacing of 100 ft in x and y-directions. This network is schematically represented in Fig. 6 by 18 fractures (7 hydraulic and 11 induced fractures) in x-direction and 8 induced fractures in y-direction. For Case2, 7 hydraulic fractures in addition to 21 induced fractures in x-direction with a spacing of 50 ft and 22 reactivated fractures in y-direction are created. Finally, for Case3, 57 fractures (7 hydraulic and 50 induced fractures) in y-direction and 41 induced-fractures in x-direction with a spacing of 25 ft are incorporated. Outside the stimulated reservoir volume, no stimulated fractures are considered. The total stimulated area is 1000 ft in y-direction and 1400 ft in x-direction.

Fig. 6 and Fig. 7 represent the grid system used for the explicit discrectized fracture model for Case1 (fracture spacing of 100 ft) and the standard dual porosity model. Fig. 8 is a shematic view of the hybrid approach based on the MINC method for the same reservoir.

Presentation of Simulation Results

In this part, single/two phase flow simulation results are presented. In the single-phase flow simulation, formation damage related to the fracturing fluid invasion is not considered in order to test the efficiency of our hybrid approach. We assume that gas is the only mobile phase in the reservoir and will be directly produced from the complex fracture network. After, simulations are performed with a two-phase (gas and water) flow model to study the impact of the fractutring fluid induced formation damage in shale gas reservoirs.

Single-Phase flow simulations

Three simulation models (explicit discretized model, dual porosity and hybrid approach) are first compared for Case1 and Case2. For the hybrid approach, MINC6 model (1 continuum for the fracture and

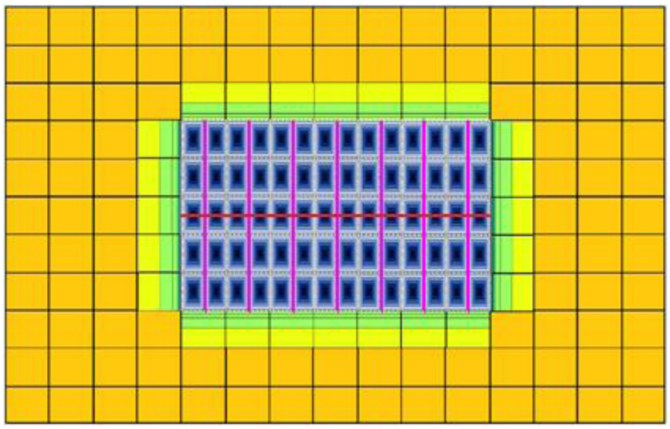


Figure 8—Hybrid approach model based on MINC method for Case1.

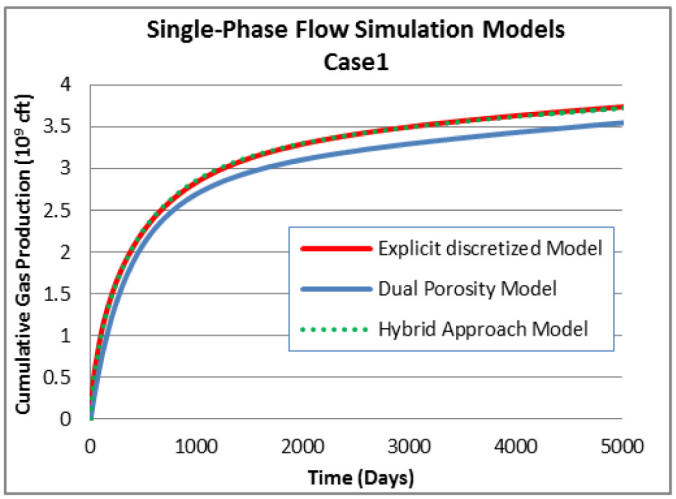


Figure 9—Comparison of different simulation models for Case1.

6 continuums for the matrix media) is used in the SRV. Fig. 9 presents the cumulative gas production for Case1 (fracture spacing of 100 ft) after 5000 days of production performed with these three simulation models. Obviously, the hybrid approach based on the concept of MINC method provides a much better result than the dual porosity model and can match accurately the explicit discretized fracture model (reference solution). Also, Fig. 10 shows the results of cumulative gas production for Case2 (fracture spacing of 50 ft). We get the same conclusions as for Case1. The hybrid approach works very well independently from fracture spacing (100 ft and 50 ft). These simulations show that the hybrid approach can predict gas production from unconventional fractured gas reservoirs. This hybrid technique using much fewer gridblocks can simulate single-phase flow problems with a good accuracy.

As the hybrid approach is quite accurate, in order to investigate the impact of fracture spacing on gas production from shale gas reservoirs, Case3 (fracture spacing of 25 ft) was simulated using the hybrid model only. Note that, simulation of Case3 with an explicit discretized fracture model was avoided by using the hybrid approach, where an explicit discretized fracture simulation could take several hours rather than seconds due to the high number of grid cells. Fig. 11 shows the difference of cumulative gas production from these three cases using a hybrid approach model for the single-phase flow simulation. In fact, decreasing the fracture spacing increases fractures number which results in enhancing gas production. As we expected, higher gas production is observed in Fig. 11 for Case3 than Case2 and Case1. Simulation

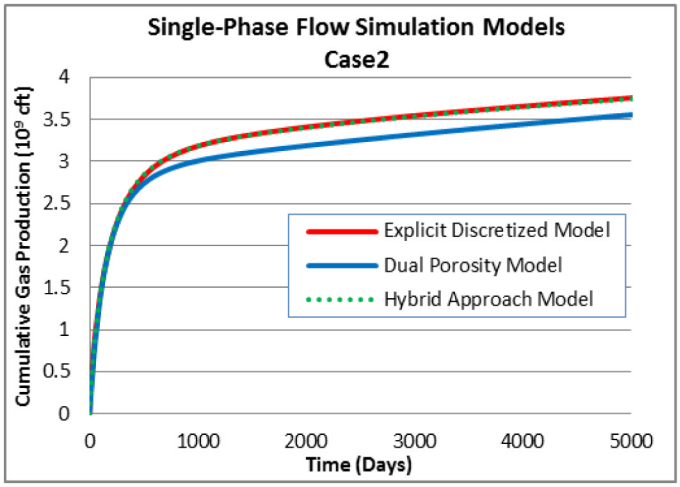


Figure 10—Comparison of different simulation models for Case2.

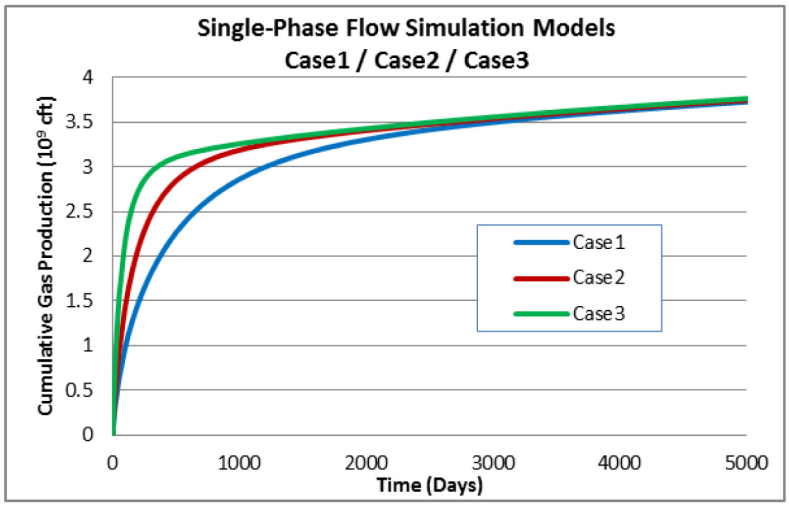


Figure 11—Comparison of the hybrid approach results for different fracture spacings.

with a hybrid approach using a MINC6 model for the whole SRV seems to be sufficient and efficient for a single-phase flow simulation.

Based on these results for a single-phase flow problem, we conclude that a standard dual porosity model is not suitable for shale gas simulations, and the hybrid model is a good approach. The hybrid model using the MINC technique proves its accuracy for the application on shale gas reservoirs. Also, MINC method improves significantly the capability to predict matrix-fracture flow exchange, where discretizing the matrix blocks into a sequence of volume elements can handle much better the transient flow from matrix into fracture during a long period instead of a pseudo-steady-state flow concerning the standard dual porosity model.

Two-Phase flow simulations

In order to improve gas production from shale gas reservoirs, fracking operations are required. With hydraulic fracturing, a huge amount of water (thousands of barrels) is injected to create multi-stage hydraulic fractures in a purpose to have an economic production from unconventional gas reservoirs. We should mention that only a part of the injected water (25-60%) is reproduced during a long period, while a significant percentage of water remaining in the reservoir and get trapped near the fracture face due to capillary effects.

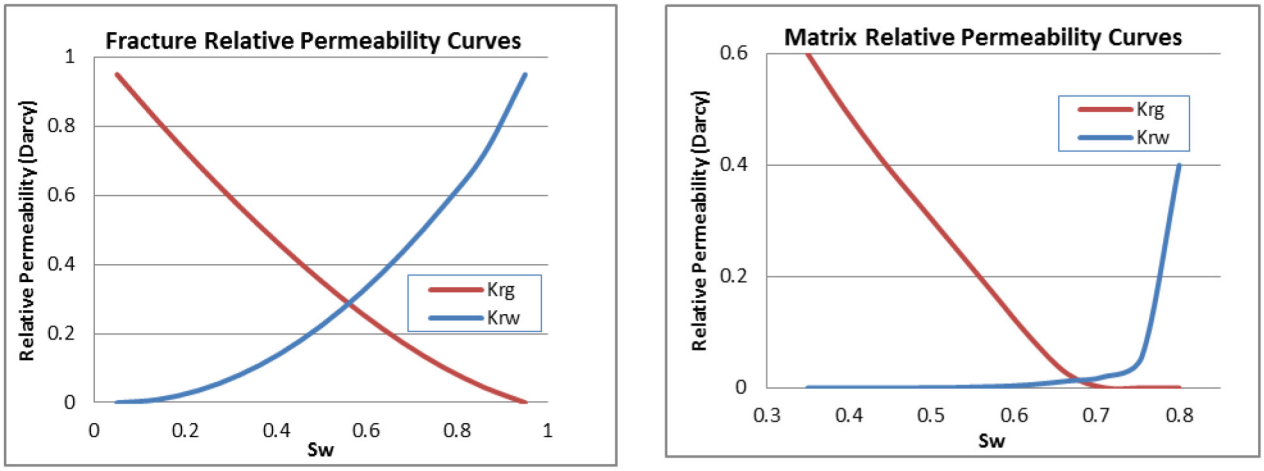


Figure 12—Fracture relative permeability curves (left) and Matrix relative permeability curves (right) vs. water saturation.

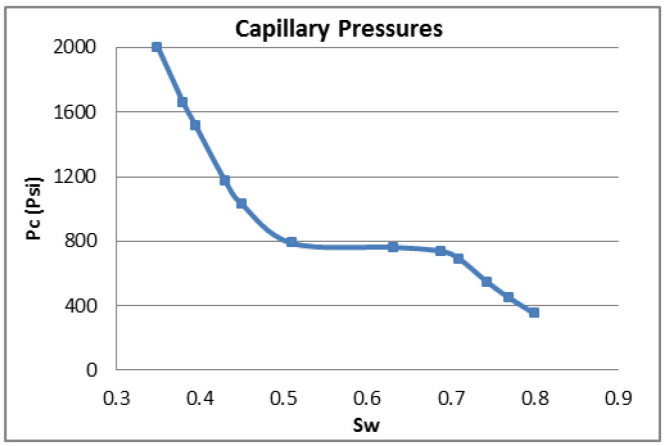


Figure 13—Capillary Pressures vs. water saturation.

With a two-phase flow model, water is first injected during hydraulic fracturing. Due to injection pressure and capillary forces, water will invade into the matrix formation. In this example, a volume of 25 000 bbl of water is pumped into the horizontal fractured well (7 fracture stages) in 5 hours. During hydraulic fracturing, fracture conductivity is usually very high due to high fracturing pressure. So, during the fracturing phase, the permeability is assumed to be 200 D in the hydraulic fractures and 40 D in the stimulated natural fractures. During the production phase, the permeability is decreased to 2 D in the hydraulic fractures and 500 mD in the stimulated natural fractures.

Both gas/water relative permeabilities in matrix and fracture media, together with the capillary pressure, are needed to be incorporated in the reservoir model for the two-phase (gas and water) flow simulation. Fig. 12 and Fig. 13 show respectively, matrix/fracture relative permeabilities and the capillary pressures versus water saturation. Furthermore, we consider the initial water saturation in this shale gas reservoir equals to the irreducible water saturation, set at 0.35.

Dealing with two-phase flow simulation, MINC6 model was not sufficient to handle fluid invasion and its backflow, as we need several very small gridblocks around the fractures to simulate correctly water invasion in the matrix formation. In order to improve our model for a two-phase flow simulation, we decided to increase the number of nested volumes related to the matrix media, by using a MINC13 model (1 continuum for the fracture and 13 continuums for the matrix media) instead of a MINC6 model (single-phase case).

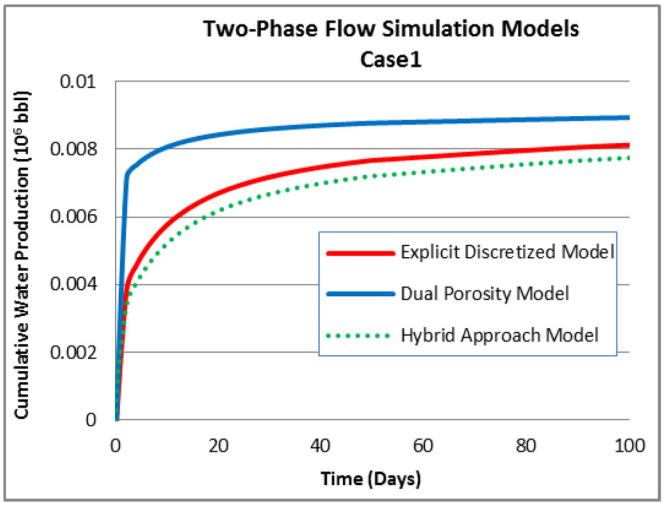


Fig. 14a–Cumulative water production vs. time.

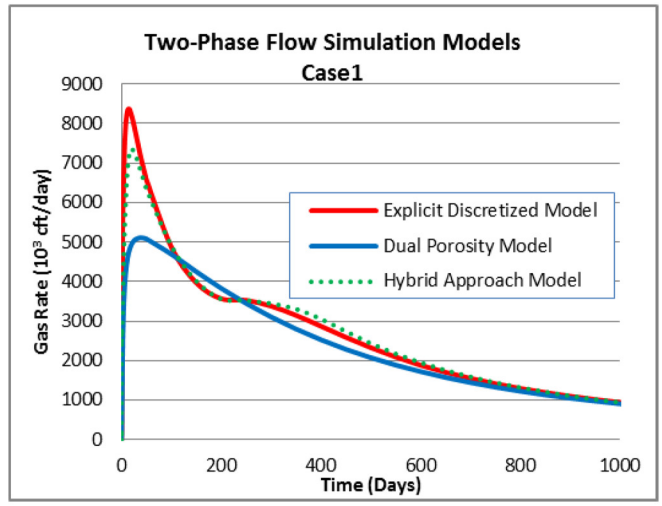


Fig. 14b–Daily gas rate vs. time.

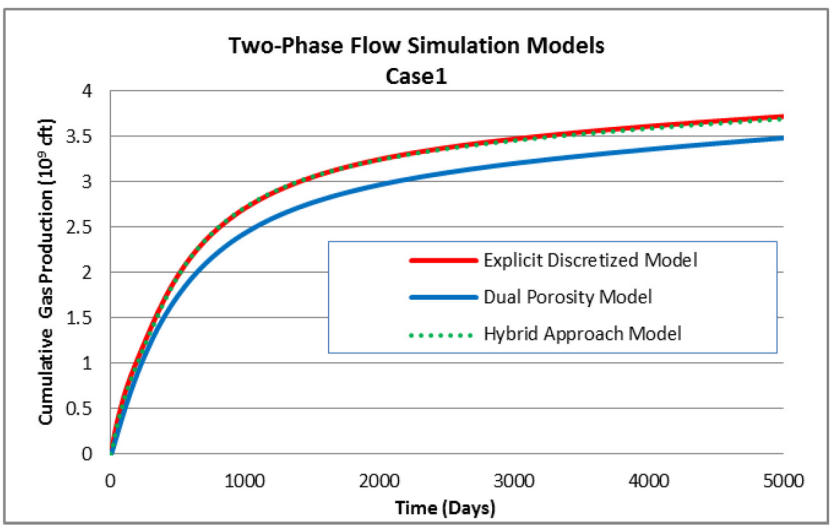


Fig. 14c–Cumulative gas production vs. time.

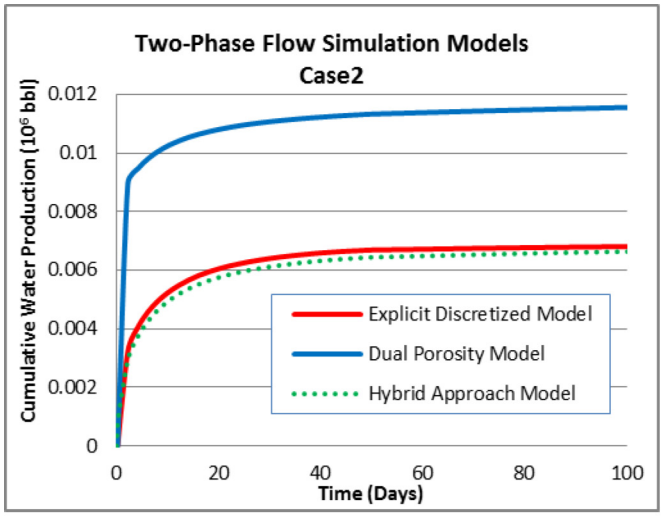
Figure 14—Comparison of different simulation models results for Case1 for a two-phase flow case.

Case1 – Fracture Spacing of 100 ft

Considering Case1, simulation results from fracture spacing of 100 ft are presented in Fig.14. The dual-porosity model and the hybrid approach are compared to the explicitly discretized fracture simulation (reference solution). Figures Fig. 14a, Fig. 14b and Fig. 14c represent respectively the results of cumulative water production, daily gas rate and cumulative gas production for this two-phase flow simulation for the same reservoir model as defined previously (see Fig. 6, Fig. 7 and Fig. 8).

Fig. 14a presents the simulated water production curves in the first 100 days. The explicit discretized model and MINC (dotted green curve) produce around 8000 bbl of water on 100 day, while the dual-porosity model produced close to 9,000 bbl. In fact, around 30% of injected water is produced, and the rest of water remains in the tight formation and needs a very long time to be cleaned. The hybrid approach gives approximately a similar water production as the explicit discretized model, where the dual porosity model is not accurate.

Fig. 14b shows the daily gas rate during the first 1000 days. The gas rate is impacted by the presence of fracturing fluid during the cleanup period. The hybrid method is not very accurate in the very early beginning, but it is much better than the dual-porosity model. If we are interested in long-term production,



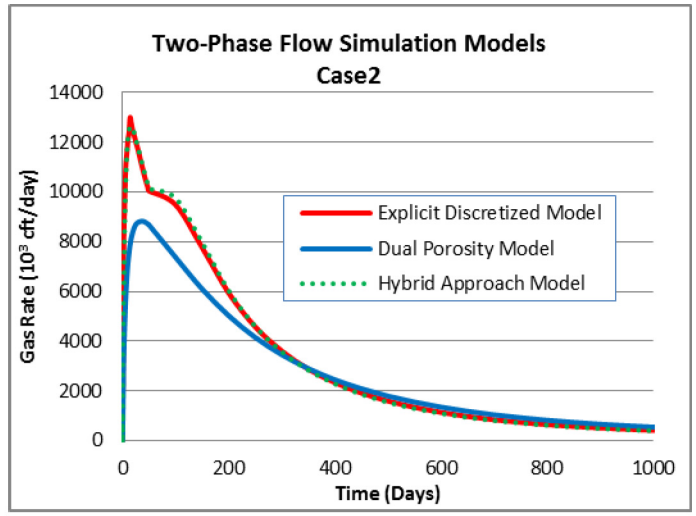


Fig. 15a–Cumulative water production vs. time.
Fig. 15b–Daily gas rate vs. time.

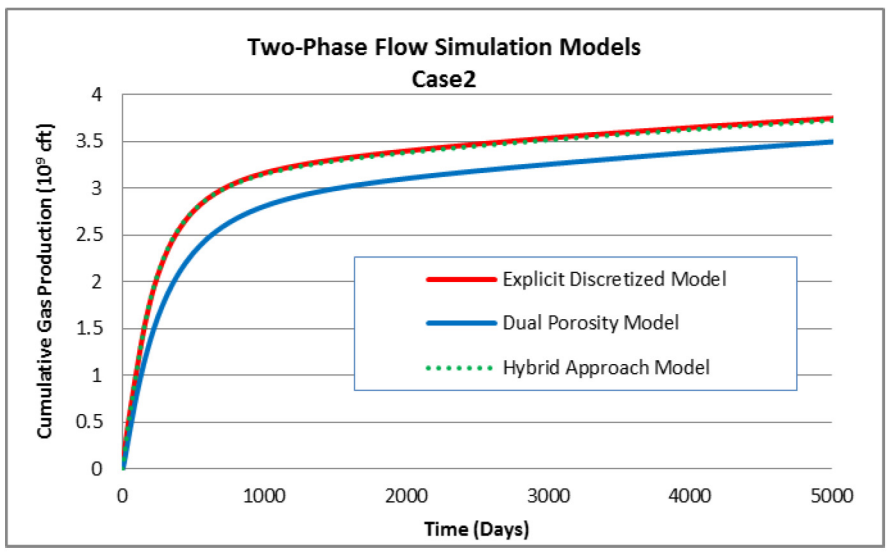


Fig. 15c–Cumulative gas production vs. time.

Figure 15—Comparison of different simulation models results for Case2 for a two-phase flow case.

based on Fig. 14c which presents the cumulative gas production for 5000 days, the hybrid method is very accurate and the dual-porosity model still not suitable.

Case2 – Fracture Spacing of 50 ft

The following simulations are carried out for the fracture spacing of 50 ft. Results are presented in Fig. 15. The water production during the first 100 days is shown in Fig. 15a. In this case, water production is reduced to 6500 bbl by the explicit discretized model and the hybrid approach. In fact, this is because the total fracture length is longer in Case2 than Case1 where smaller fracture spacing is treated and then obviously a larger fracture face will be in contact with the matrix formation. So, little water is invaded into the matrix formation per unit of fracture surface. It is more difficult to remove a small quantity of water, due to the water blocking effect and the present of a high capillary pressure (2000 psi). In other words, decreasing the fracture spacing increases the number of fractures and the exchange surface with the matrix media, and therefore the water invasion is extended to a very larger area and the water backflow is globally reduced. The produced water from Case2 corresponds to 25% of injected water. The hybrid

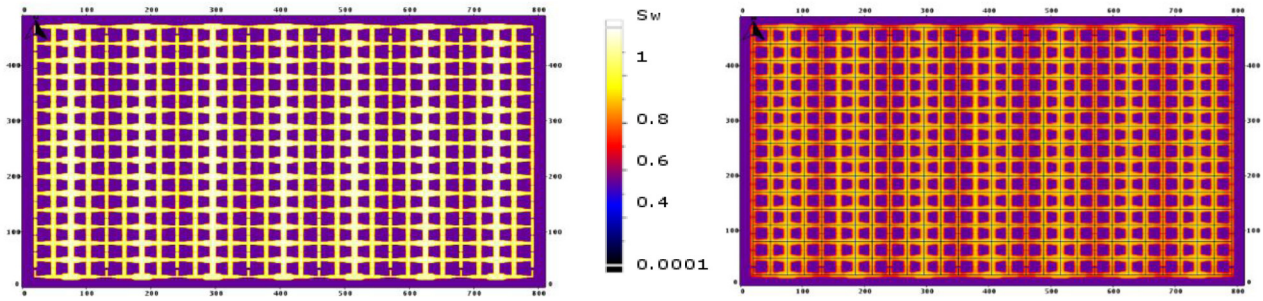


Fig. 16a–After 5 hours

Fig. 16b–After 50 days

Figure 16—Water saturation distribution (Fracture Spacing of 50 ft)

simulation in this case is more accurate than the previous case (fracture spacing of 100 ft). This is because the water invasion in this case is shallow in the matrix formation, and MINC13 is sufficiently fine around the fracture to simulate this water invasion. Moreover, the shorter transient period due to small block sizes also helps to improve the MINC simulation accuracy. On the contrary, the dual-porosity model highly overestimates the water production and is not accurate. Fig. 15b presents the daily gas rate gas in early time and Fig. 15c shows the cumulative of gas production for 5000 days. The hybrid method is very accurate in both early time and long-term periods. The dual-porosity model is always not accurate.

The simulations of these two cases (fracture spacing of 100 ft and 50 ft) allow us to confirm that the hybrid approach is accurate and can be used as a reference solution for further simulations. The hybrid approach can be used to simulate matrix-fracture exchange even for a multiphase flow case independently from fracture spacing (Case1 and Case2). In the following, we will use the hybrid method as the reference solution to simulate the case of fracture spacing of 25 ft to investigate the effect of formation damage.

Impact of Fracturing Fluid Induced Formation Damage

Due to the high-pressure, water-based fracturing fluid will invade through matrix media. Then, water is trapped in the tight formation, and only a percentage of the injected water can be produced. Unproduced water will lead to a blocking effect in the matrix formation due to high capillary pressures and water sensitive clays. The presence of water will unfortunately reduce gas relative permeability and may impact gas production from shale gas reservoirs.

In order to illustrate the impact of water invasion, Fig. 16 shows some illustrative figures for the fracture spacing of 50 ft (Case2), where the cells near the fractures are zoomed. In these figures, water saturations inside and near fracture cells are illustrated at the end of injection (after 5 hours) and at the 50th days of production. After 5 hours of water injection, fracturing fluid invades around 0.15 ft into the matrix formation. After 50 days of gas production, water saturation is still around 0.65 – 0.75 in the tight formation near the fracture faces. A lot of time is needed to clean the invaded water.

In this section, we will study the impact of fracturing fluid induced formation damage by comparing the single-phase flow simulation, where no formation damage is considered, and the two-phase flow simulation, where the formation damage due to fracturing fluid invasion is taken into account.

Fig.17 presents these comparisons for fracture spacing of 100 ft, 50 ft and 25 ft (Case 1, Case 2 and Case 3) respectively. We notice that gas productions from single phase flow simulations (no formation damage) are higher than those from two-phase flow simulations (fracturing induced formation damage), because of capillary trapping, etc. This methodology can be used to evaluate quantitatively the effect of fracturing fluid induced formation damage.

The formation damage for Case1 is more important than Case2 at earlier time of production, while it can almost be neglected in Case3. In fact, we can notice that the formation damage becomes less important when the number of fractures increases (decreasing the fracture spacing). This result can be explained by

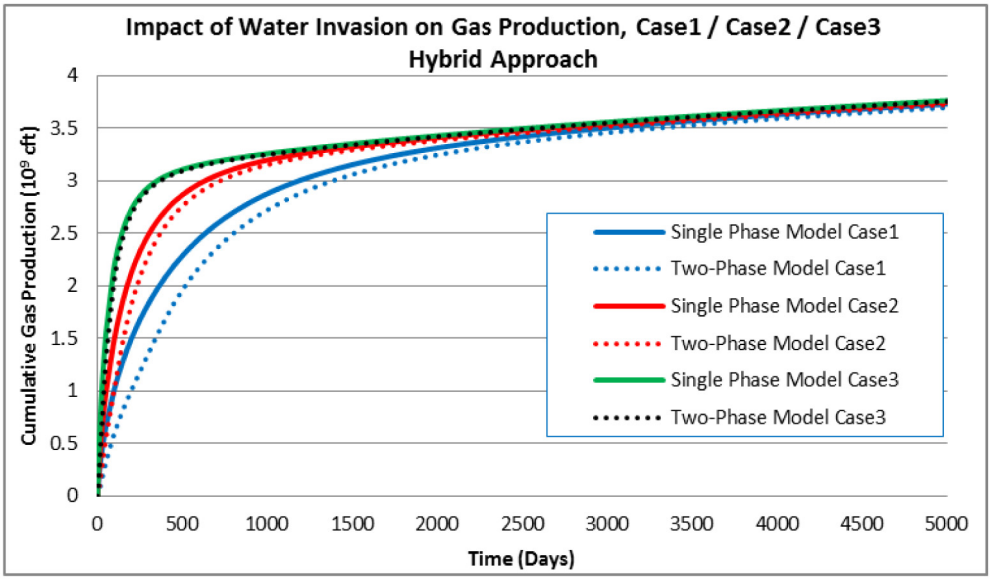


Figure 17—Impact of water invasion on gas production for Case1, Case2 and Case3.

Table 3—Comparison of CPU time between the explicit model and the hybrid approach for each case.

		Single Phase Flow Simulations		Two-Phase Flow Simulations			
Simulation Model	Case	N° of Grids	CPU Time (sec)	N° of Grids	CPU Time (sec)	Invasion Depth (ft)	Smaller Grid Volume (ft^3)
Explicit discretized fracture Model	Case 1	147063	7841	147063	20262	0.27	0.0003
	Case 2	396579	28702	396579	84211	0.15	
	Case 3	Not Simulated		Not Simulated			
Hybrid Approach	Case 1	**1039 (MINC6)**	**8.0**	**1529 (MINC13)**	**12.0**	0.27	120
	Case 2					0.15	240
	Case 3					0.07	480

the formation damage through water invasion depth. In fact, when fractures are dense, the volume of water invasion into the matrix formation by unit fracture surface becomes small. Once the fluid invasion is shallow, the impact of water invasion on gas production will be insignificant.

A summary of numerical simulation results is presented in Table 3, which includes the number of gridblocks, CPU time, average water invasion depth, and the smallest gridblock volume. Table 3 compares the CPU time between the explicit discretized fracture model and the hybrid approach for single and two-phase flow simulations for each case. For the single phase flow simulations, an explicitly discretized fracture model took 7841 seconds and 28702 seconds respectively for Case1 and Case2, while for the hybrid model with MINC6 in which uses only 1039 gridblocks, an average of 8 seconds of CPU time was taken in the simulation for each case independently from the fracture spacing. It has to be mentioned that Case3 was not simulated using an explicit dicretized model due to the high number of grids cells (1.5 millions grids approximately). Furthermore, concerning the two-phase flow simulations, an enormous CPU time is required with the explicit discretized fracture model (20262 and 84211 seconds respectively for Case1 and Case2). The hybrid approach is much more efficient and faster than the explicitly discretized model. The CPU time is reduced to 12 seconds for all the three cases with a MINC13 model (1529 meshes for a two-phase flow simulation independently from fracture spacing). This approach decreases significantly the number of grids meshes and the CPU time compared to an explicit discretized model. Also, the accuracy of MINC method does not depend on the fracture spacing.

It is clear that an explicit discretized model takes a lot of CPU time. The large number of gridblocks required in an explicitly discretized model increase the CPU time in solving the system at one time step, and also small volume of gridblocks constrain the time steps (need to use very small time steps). Table 3 also presents the smallest grid volume for each case for different simulation models. It is shown the smallest block volume for the hybrid approach is 6 orders of magnitude greater than that of the explicit fracture discretization model (0.0003 ft^3 for the explicit discretized model and 120 ft^3, 240 ft^3 and 480 ft^3 respectively for Cases 1, 2 and 3). The explicitly discretized model is greatly penalized in CPU time, especially for two-phase flow problems.

Concerning the depth of fracturing fluid invasion, it is 0.27 ft for the large fracture spacing of 100 ft. This depth is reduced to 0.15 ft for the fracture spacing of 50 ft and reduced to only 0.07 ft for the small fracture spacing of 25 ft. This observation confirms the results from Fig. 17. For Case1, water invasion is deeper, so the effect of formation damage is greater. The impact of fracturing fluid induced formation damage may last several years.

Through this example, the accuracy of the hybrid approach based on the MINC method is demonstrated. This approach can be used for both single-phase and two-phase flow simulations, and it takes much less CPU time comparing to an explicit discrete fracture model. It can be used to study the effect of fracturing fluid induced formation damage.

Finally, the proposed hybrid approach can easily be applied to a larger SRV case, as both the required number of gridblocks and the CPU time are small. We will consider, in future studies, the simulation of a very large stimulated reservoir volume with, for example, 30 multi-stage fractures using the hybrid approach. This kind of problem is almost impossible to be simulated with an explicitly discretized fracture model. Also, future work will treat discrete fractured network (DFN). Note that, the application of MINC method is not limited to a regular network and can be also be applied on an irregular one.

Discussion

To model a realistic reservoir fracture network, new type of models called discrete fracture model (DFM) have received a great attention. These kinds of models consist in discretizing complex fracture networks. Many techniques using DFM models were tested and studied in the literature, most applicable models called as unstructured discrete-fracture model (USDFM), embedded discrete-fracture model (EDFM) and integrate discrete fracture model (iDFM) (see, for example, Lee et al., 2001; Karimi-Fard et al., 2006; Ali Moinfar et al., 2011 and 2013; Jack Norbeck et al., 2014).

The ability of the hybrid approach with MINC method was tested for the simulation of two-phase flow with a regular fracture network in this paper. Moreover, MINC method is not limited to a regular fractured network, and can be extended to an irregular network (see for example, Pruess K. 1982). Future work will study multi-phase flow modeling techniques with a discrete fracture network in order to simulate a realistic shale gas reservoir, where fracture network complexity increases. The MINC method will be considered for a better modeling concerning the matrix-fracture flow exchange in an irregular fracture network.

Conclusions

This paper discusses a hybrid approach based on the concept of MINC method for the simulation of gas production from unconventional shale-gas reservoirs. This approach treats the interporosity flow entirely in a fully transient way for the matrix-fracture flow exchange. Based on the results, the hybrid method provides very accurate simulations, comparing with finely meshed explicit discretized fracture model. An explicit discretized model is not suitable for unconventional reservoir simulations and will take a lot of CPU time, especially for two-phase flow problems. Using the hybrid approach based on the concept of MINC method allows us to avoid such simulations where a hybrid approach decreases significantly the CPU time comparing to an explicit discretized model.

Hybrid approach based on the MINC method can handle formation damage issue in low permeability reservoirs. The fracturing fluid induced formation damage is particularly studied. Simulation of fracturing fluid invasion and its backflow needs very fine gridblocks near the fracture face for a better flow modeling into and from the fractures. This approach is suitable for the study of formation damage, as long as small block sizes are used near the fracture. The impact of formation damage may be great, depending on the depth of fracturing fluid invasion into the matrix formation.

The hybrid approach is suitable for both single-phase and multi-phase flow simulations in shale gas reservoirs. Moreover, it can be easily applied to a larger SRV case, which gives us the possibility to perform sensitivity tests (fracture apertures, fracture permeability, matrix permeability, etc.) and study advanced physical processes (adsorption and desorption, geomechanics aspect, Klinkenberg effect, etc. . .), together with the formation damage issue for field cases.

Nomenclature

a = *matrix block dimension*
b = *matrix block dimension*
k_{rg} = *gas relative permeability*
k_{rw} = *water relative permeability*
P = *pressure*
q = *source/sink term*
Q_p^{mf} = *matrix-fracture interaction for phase p*
S = *fluid saturation*
t = *time*
V_E = *volume of adsorbed gas in standard condition per unit mass of solid*
v_β = *volumetric velocity vector of fluid* β
m_g = *adsorption or desorption term per unit volume of formation*
ϕ = *effective porosity of formation*
Φ = *flow potential*
$\lambda_{p,\,ij}$ = *mobility of phase p between gridblcoks i and j*
μ = *viscosity*
σ = *shape factor*
ρ_r = *solid rock density*
ρ_g = *gas density*

subscript

f = *denote fracture*
g = *gas*
m = *denotes matrix*
β = *index of fluid phase*
w = *water*

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